DIRECT TESTIMONY OF

BRENDAN KIRBY

ON BEHALF OF

SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND

SOUTHERN ALLIANCE FOR CLEAN ENERGY

DOCKET NO. 2019-2-E

INTRODUCTION AND QUALIFICATIONS

Q Please state your name, position, and business address for the record.

A Brendan Kirby, P.E., Consultant, 12011 SW Pineapple Court, Palm City, Florida, 34990.

Q Please summarize your professional and educational qualifications.

A My qualifications are attached to my Expert Report as Appendix A.

Q Have you previously filed testimony as an expert witness in a regulatory proceeding?

A Yes. I have filed testimony in proceedings regarding wind and solar integration, bulk power system reliability, ancillary services, and demand response before Commissions in California, Minnesota, Texas, Wyoming, and Hawaii, as well as before the Federal Energy Regulatory Commission. I was also appointed as the Special Advisor for Demand Response for the Hawaii Commission in 2015.

Q On whose behalf are you testifying in this proceeding?

A The South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy.

Q Are you sponsoring any exhibits?

A Yes, an Expert Report titled "Analysis of SCE&G's Proposed Variable Integration Charge," included as Exhibit BK-1.

Q What is the purpose of your direct testimony in this proceeding?

A The purpose of my direct testimony in this proceeding is to review and evaluate SCE&G's proposed Variable Integration Charge. I discuss why the methodology used to develop the proposed Variable Integration Charge is fundamentally flawed, and as a result, the Variable Integration Charge is unsupported, inappropriate, and should be rejected by the Commission.

REVIEW OF VARIABLE INTEGRATION CHARGE AND CONCLUSIONS

Q Please provide a brief overview of SCE&G's proposed variable integration charge.

A SCE&G's proposed variable integration charge is based on an analysis that attempted to determine the amount of additional reserves SCE&G must operate in order to compensate for potential errors in the solar forecast.

Q Have you reviewed SCE&G's witness testimony regarding the proposed variable integration charge?

A Yes, I reviewed the Direct Testimony of Matthew W. Tanner, Ph.D., Exhibit No. (MWT-2), and the report Cost of Variable Integration, Navigant Consulting, February 2019 contained in that testimony.

Q What is your reaction to that testimony and SCE&G's proposal?

A The basic premise that adding variable renewable generation to the power system may increase operating costs is not unreasonable. The use of hourly production cost modeling and comparing cases with and without additional solar generation is also sound. Unfortunately, however, the analysis as implemented is deeply flawed. As a result, the costs of variable integration developed in the Cost of Variable Integration study do not reflect actual increased reserve requirements or actual impacts on the operating costs that SCE&G will likely experience as a result of increased solar generation. The analysis method and tools should be updated to reflect actual utility reliability requirements, capabilities, and operations. The solar data should be reanalyzed to reflect plant, forecasting, and system aggregation benefits.

Q Please provide an overview of the primary issues you have identified with the Cost of Variable Integration study SCE&G has presented.

A The report attached as Exhibit BK-1 details concerns with the Cost of Variable Integration analysis and the resulting proposed integration charge. There are several serious concerns with the analysis method:

First, the analysis failed to account for aggregation benefits that naturally reduce relative forecasting errors as the solar generation fleet grows.

Second, the analysis used an excessive 4-hour ahead forecast, overstating the forecast error that actual operations will have to deal with. Alternatively, the analysis failed to include off-line combined cycle (CC) generation capacity as available reserves that can mitigate 4-hour ahead solar forecast errors.

Third, additional fixed solar reserve requirements were imposed 8760 hours a year rather than as a function of the hourly forecasted solar generation, likely greatly overstating additional reserve costs. To try to overcome the problem that imposing a fixed annual solar reserve requirement results in overstating solar reserve costs, the results from multiple production cost modeling runs with different reserve requirements were inappropriately "blended." But this failed to correct the problem introduced with holding extra solar reserves constant for 8760 hours per year.

Fourth, the analysis failed to recognize that reserve shortfall events will be infrequent, that actual solar generation shortfalls will be even less frequent, and that the shortfalls are relatively easily mitigated.

Fifth, the analysis failed to include significant additional reserves from the Fairfield Pumped Storage plant and from interruptible load that are appropriately available as solar forecast error reserves.

Q What would be necessary to rectify the issues you have identified with the Cost of Variable Integration study SCE&G has presented?

A The analysis methodology should be modified, and the modeling tools upgraded. As explained in more detail in my report:

- Production cost modeling should accurately reflect the aggregation benefits that naturally reduce forecasting errors as the solar generation fleet grows. Solar output and forecast data should be analyzed using a realistic representation of geographic diversity and solar plant sizing for the high penetration solar cases.
- The solar forecast error analysis that determined the MW reserve requirements should be redone with a 2-hour ahead or 1-hour ahead solar forecast. Alternatively, if the 4-hour ahead solar forecast is kept then off-line combined cycle (CC) units should be counted as available reserves.
- Production cost modeling should be redone with reserve requirements adjusted hourly to reflect the actual solar conditions. The analysis method of "blending" results from

multiple production cost modeling runs, each with fixed reserves imposed 8760 hours a year, should be discarded. If the modeling tools or techniques are not adequate to represent actual conditions and requirements, fix or replace them.

- The analysis methodology should recognize that times of high additional solar forecast error reserves are infrequent, and that times of required reserve response are even more infrequent. Reserve technologies and mitigation strategies that are better suited for these infrequent events should be selected to supply the required reserves at minimal cost.
- Production cost modeling should include the Fairfield pumped storage plant pumping load and off-line generation as available reserves for solar integration, subject only to the constraint of available storage capacity.
- Production cost modeling should include the additional 100 MW of interruptible load that VACAR does not permit SCE&G to count towards the contingency reserve obligation as available reserves for solar integration.

Once these steps are taken, it will be possible to begin to determine if any solar integration charge is warranted.

Q What is your conclusion regarding SCE&G's proposed variable integration charge given the issues you have identified with the Cost of Variable Integration study?

A The analysis flaws need to be fixed to determine if a charge is warranted. The Commission should reject the charge as currently proposed until SCE&G presents more evidence and reruns its analysis.

RECOMMENDATIONS

Q Please summarize your recommendations for the Commission.

A The Commission should direct SCE&G to redo the production cost analysis. Realistic solar data should be generated that accurately reflects the aggregation effects that are associated with large, geographically diverse, solar generation resources. A 2-hour ahead or 1-hour-ahead solar forecast should be used to determine potential additional reserve requirements. Alternatively, off-line combined cycle units should be counted as available solar integration reserves. Most importantly, the production cost modeling should be performed with additional reserve requirements adjusted hourly based on the hourly forecast solar production, to reflect the actual reserve requirements that the power system will require and to reflect how the power system will actually be operated. Interruptible load, Fairfield pumping load, and Fairfield's ability to switch from pumping to generating should all be included as solar integration reserve resources, reflecting the fact that reserves will be required relatively infrequently, and these resources are ideal at supplying infrequent reserves. Once these steps are taken it will be possible to begin to determine if any solar integration charge is warranted.

Q Does this conclude your testimony?

A Yes.

Exhibit BK-1

Analysis of SCE&G's Proposed Variable Integration Charge

Brendan Kirby, P.E – March 2019

The proposed variable integration charge was developed for SCE&G by Navigant Consulting and documented in a February 2019 report titled "Cost of Variable Integration."[1] The basic premise that adding variable renewable generation to the power system may increase operating costs is not unreasonable. The use of hourly production cost modeling and comparing cases with and without additional solar generation is also sound. Unfortunately, the Navigant analysis, as implemented, is deeply flawed for several reasons:

- The analysis failed to account for aggregation benefits that naturally reduce the relative forecasting errors as the solar generation fleet grows.
- The analysis used an excessive 4-hour ahead forecast, overstating the forecast error that may impact actual operations. Alternatively, the analysis failed to include off-line combined cycle (CC) generation capacity as available reserves that can mitigate 4-hour ahead solar forecast errors.
- Additional fixed solar reserve requirements were imposed 8760 hours a year rather than being a function of the hourly forecasted solar generation, likely greatly overstating additional reserve costs.
- In an attempt to overcome the problem that imposing a fixed annual solar reserve requirement results in overstating solar reserve costs, Navigant inappropriately "blended" the results from multiple production cost modeling runs with different reserve requirements. This approach does not correct the overstatement of solar reserve costs caused by holding extra solar reserves constant for 8760 hours per year.
- The analysis failed to recognize that reserve shortfall events will be infrequent, even with SCE&G's conservative assumptions; that actual solar generation shortfalls will be even less frequent; and that the shortfalls are relatively easily mitigated.
- The analysis failed to include significant additional reserves from the Fairfield Pumped Storage plant and from interruptible load that are appropriately available as solar forecast error reserves.

As a result of these deficiencies, the costs of variable integration developed in the *Cost of Variable Integration* study do not reflect actual increased reserve requirements or actual impacts on the operating costs that SCE&G will likely experience as a result of increased solar generation. The analysis method and tools should be updated to reflect actual utility reliability requirements, capabilities, and operations. The solar data should be reanalyzed to reflect plant, forecasting, and system aggregation benefits.

[1] Direct Testimony of Matthew W. Tanner, Ph.D., Exhibit No. (MWT-2), *Cost of Variable Integration*, Navigant Consulting, February 2019.

Please note that when discussing specific examples this report primarily refers to SCE&G's highest solar penetration, Solar Case 2 (SC2), with ~1050 MW of solar generation. This case presents the greatest integration challenges, so solutions that mitigate solar integration concerns at this level are even more effective at lower solar penetrations.

Inappropriately High Reserve Requirements

The SCE&G proposed variable integration charge is based on the added reserves needed to compensate for errors in the 4-hour ahead solar generation forecast:

> "Navigant conducted a solar uncertainty analysis, which estimated the forecast error for solar generation installed on the system. The purpose of this analysis was to determine the amount of operating reserves that must be maintained by the Company in order to ensure that SCE&G can reliably respond and meet system needs if actual generation is less than forecasted."[2] (page 7)

While solar forecast error is a legitimate concern, SCE&G imposed excessively high reserve requirements when developing the variable integration charge because they failed to account for diversity aggregation benefits as the solar generation fleet size is increased. SCE&G also used an unreasonably long 4-hour ahead solar forecast when a 2-hour ahead forecast, with correspondingly lower forecast error, better matches the SCE&G system capabilities. If SCE&G is actually operating based on a 4-hour forecast when a 2-hour forecast is more appropriate, then it is wasting fuel by holding too many reserves and causing an excessive fuel cost within this fuel cost docket. The Commission should consider disallowing any excess fuel costs if SCE&G does not move to a 2-hour or shorter forecast.

The Analysis Failed to Appropriately Account for Aggregation Benefits for Solar Forecasting

In order to quantify solar forecast error Navigant used a year of 5-minute solar data supplied by the National Renewable Energy Laboratory (NREL) from four sites in the SCE&G service territory. NREL also provided a 4-hour ahead hourly forecast for each site. The *Cost of Variable Integration* report explained that "[a]veraging the forecast error among multiple locations properly accounts for the expected geographic diversity of solar resources being added to the system. This ensures that the analysis is not too aggressive in estimating the additional reserves needed by SCE&G." (page 23) The report is correct that averaging the forecasts from four sites reduces the forecast error. The report is misleading if it implies that forecast error will not be further reduced when more solar generators are added to the aggregation.

Analyzing the solar output and forecast data from all four sites for the entire year shows that the average forecast error is reduced by 24% when compared with summing the errors from individual sites. There is no reason to assume that forecast aggregation benefits stop with a four-solar-plant aggregation. As the solar fleet increases to over 1000 MW it will be composed

[2] Direct Testimony of Matthew W. Tanner, Ph.D., Exhibit No. (MWT-2), *Cost of Variable Integration*, Navigant Consulting, February 2019.

of tens to thousands of solar generators spread over the entire SCE&G service territory. Aggregation benefits will significantly reduce short-term forecast errors as well as short-term solar output volatility.

Recommendation: The Commission should direct SCE&G to analyze solar output and forecast data from a realistic representation of geographically diverse and realistically sized solar plants for the high penetration solar cases.

The Analysis Failed to Appropriately Account for Aggregation Benefits for Solar Generation

Solar generation variability itself is also significantly overstated in the *Cost of Variable Integration* analysis. This impacts the cost of production as conventional generators must respond to greater-than-actual hour-to-hour changes in aggregate solar output. Actual solar variability declines significantly with aggregation but SCE&G confirmed that "[t]he 8760 shapes used in the analysis were linearly scaled with total installed solar MW nameplate."[3] The *Cost of Variable Integration* report states that "[t]he hourly shape for solar generation that is inputted into PROMOD is developed from an aggregation of real solar generation hourly shapes from SCE&G." (page 20) SCE&G stated that "[t]he data was actual hourly operating data for 7 projects installed on the SCE&G system."[4] These seven projects had a name plate capacity of 46.68 MW. Analysis of the year of data shows that average hour-to-hour variability for the aggregation was 51% less than the average hour-to-hour variability of the individual plants. That is, increasing the solar fleet size by a factor of seven cut the hour-to-hour variability in half. Increasing the solar fleet size by another factor of 22, to the SC2 level of ~1050 MW, will again significantly reduce the hour-to-hour solar variability.

The 2030 hourly production cost modeling for the SC2 case includes 40 named solar plants, but the output from many of the plants is perfectly correlated with the output from other plants. For example, the hourly outputs for Barnwell Solar Farm, Estill Solar I Project, Estill Solar II LLC, Haley (Allendale) Solar Farm, Hampton Solar 1, and Hampton Solar 2 are all perfectly correlated. These do not represent six separate solar plants but are six copies of the same facility. There are only 19 independent entities in the PROMOD analysis. Each of these may still overstate variability since the output of a single larger plant is inherently less variable (on a percent of name plate basis) than the output of a smaller solar plant because of the necessarily larger physical size of the larger solar plant.

Recommendation: The Commission should direct SCE&G to more accurately model the actual geographic diversity and aggregation benefits of the expected solar fleet in high penetration solar cases.

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[3] Response to South Carolina Conservation League and Southern Alliance for Clean Energy Third Data Request 3-11.
[4] Response to South Carolina Conservation League and Southern Alliance for Clean Energy Third Data Request 3-12.

The 4-Hour Ahead Forecast Is Excessive – Alternatively, Off-Line CCs Should Qualify as Reserves

Solar forecast error naturally declines closer to the operating hour. The least reserves are required, and the lowest costs will be incurred, if the most accurate, and therefore shortest-term forecast, is used. A forecast generated just before a system operator needs to decide whether to take action (starting an additional CC unit to supply additional reserves, for example) will result in the least required reserves and the lowest added cost.

Navigant's *Cost of Variable Integration* study used the readily available NREL 4-hour ahead solar forecast that is coupled with the NREL 5-minute solar data. Navigant makes the following claim that the use of a 4-hour ahead solar forecast is justified:

> "This is appropriate because as the solar generation changes in the period between the 4-hour ahead forecast and actual operation, SCE&G will not have sufficient time to turn on any additional CC or ST units. The only reserves that are available are the additional generating capacity, or headroom, for Fairfield, Saluda, the CTs, and the CCs and STs that are already online." (page 21)

When asked why a 2-hour ahead forecast was not used, since many of the SCE&G CC units and most of the CT units can start in under 2 hours, SCE&G stated:

> "The 4-hour forecast is an appropriate estimate for the forecast error because, although some of the CCs can start in 2 hours, there would need to be some lead time between receiving the forecast <u>and discovering that it is less than the expected solar generation. This assumption is that SCE&G would not be able to know whether the forecast was wrong for at least two hours</u> after receiving the four-hour ahead forecast. This analysis is conservative in that many of the ST plants on the system and a few of the CCs need longer than 2-4 hours to start."[5] (emphasis added)

This response misses the point of reserves. Variable integration reserves are designed to protect against the possibility that the solar forecast is so wrong that there won't be enough reserves to cover any drop in actual solar generation.[6] The operator does not need to determine if the current forecast is accurate; the reserves are being held precisely in case the forecast is wrong. If there is time to determine if the forecast is correct, then there is no need for forecast-error-reserves. With a 2-hour ahead forecast there is no need to wait and determine if the solar forecast is accurate. The reserve requirement is based on the forecast amount and already incorporates the risk that the forecast is wrong. If the 2-hour ahead forecast estimates a solar generation level that indicates the need for an additional CC to be operating to supply reserves, the CC can begin to be started immediately.

[5] Response to South Carolina Conservation League and Southern Alliance for Clean Energy Third Data Request, 3-14.
[6] The reserve criteria actually protects against all but 1% of the potential forecast errors.

The *Cost of Variable Integration* study also did not allow off-line CC plants to provide any reserves. As SCE&G states, with a 4-hour ahead forecast there is ample time to start an off-line CC after determining that the 4-hour ahead forecast is in error.

Recommendation: The Commission should direct SCE&G to shorten its forecast interval to one to two hours, with an equivalent reduction in estimated forecast error. Alternatively, off-line CCs should be allowed to provide reserves. If SCE&G actually operates using the 4-hour forecast that is described in the Navigant study and also acquires the capacity that it predicts that it needs in order to have sufficient solar reserves, the Company will be overcharging for both fuel and capacity, likely by millions of dollars. Directing SCE&G to operate on a two-hour forecast rather than a four-hour forecast would avoid the waste of fuel and acquisition of costly unnecessary capacity.

Modeling Methodology Concerns

The *Cost of Variable Integration* analysis is based on additional reserve requirements that arise because solar generation forecasts are not perfectly accurate. This is reasonable. Naturally, the amount of solar that is forecasted to be online varies from hour to hour. Much of the solar variation is not subject to forecast error. For approximately half of the 8760 hours in the year (at night), there will be no solar generation and no forecast error and no one should be charged to provide solar reserves during these hours. Further, the required reserves during the day vary from hour to hour but will never be greater than the solar plant's full capability after accounting for the rotation of the earth.

Unfortunately, (as discussed in more detail below) Navigant was unable to model a reserve requirement that changes hourly. Instead, they imposed a flat added solar reserve requirement 8760 hours a year. Navigant acknowledges that this modeling approach overstates the actual reserve requirements and reserve costs, and attempts to address this issue by performing and "blending" multiple modeling runs—each with a different solar reserve requirement (but each still imposed 8760 hours a year)—to calculate the final solar integration cost. This approach is analogous to calculating the energy value of solar by modeling the power system with no solar and with a 1050 MW block of firm energy forced on the system 8760 hours a year and then crediting solar with 24% of the cost difference because solar has a 24% capacity factor. The fuel savings benefits and the operating challenges and costs would be completely misrepresented by modeling a 1050 MW block of firm energy. The results would never be accepted as an accurate model of solar integration, even if they were scaled by the capacity value of solar.

The method of modeling fixed annual added solar reserves is simply wrong. As further explained below, Navigant's "blending" method does not fix the underlying error in the analysis.

Additional Reserve Requirements Were Imposed 8760 Hours per Year

The *Cost of Variable Integration* report notes "that the level of solar generation uncertainty depends on the level of solar generation. The amount of reserves that need to be held by SCE&G

for variable integration depend on the level of 4-hour-ahead forecasted solar generation." (page 18) SCE&G established a severe 99% confidence criteria for solar generation forecast shortfalls. Table 9 of the *Cost of Variable Integration* report shows that the maximum solar forecast shortfall reserve requirement (based on the 99% confidence requirement) varies as a function of 4-hour ahead forecasted hourly solar generation. (page 23)

The production cost modeling, however, did not adjust the solar forecast reserve requirements hourly based on the forecasted solar generation. Instead, SCE&G explained that "[d]ue to PROMOD's structure, the reserve requirements were increased in all hours."[7] That is, fixed reserve requirements were imposed in all 8760 hours of each year and reserves were not adjusted based on expected solar generation, as would be done in actual operations, simply because of a modeling limitation. SCE&G therefore proposes to penalize solar generators based on an analysis that imposed high reserve requirements far in excess of the amount of solar generation on line during most hours of the year. This makes no sense and almost certainly results in calculation of unreasonably high production cost.[8]

SCE&G attempts to justify the analysis method by stating that "There are a limited number of hours in which the reserve requirements are a binding constraint that forces system operation to change and these hours are <u>generally</u> in the middle of the day when solar is on line."[9] (emphasis added)

This analysis technique of requiring solar reserves 8760 hours a year, regardless of actual solar generation, is troubling because solar generation inherently creates its own reserves. This can be illustrated with an overly simplistic example. Say a utility is meeting its 5000 MW peak load with conventional generation.[10] The utility adds 1000 MW of solar generation and the net-load that the conventional generation must meet is now 4000 MW. If the sun is shining this releases 1000 MW of conventional generation. Say too that the utility determines that there is a 1% chance that solar will be 40% below its 4-hour ahead forecast and thus establishes a 40% solar reserve requirement. During the example hour 400 MW of the freed-up generation must be held in reserve in case solar generation falls short of the forecast.

If the utility changes the solar reserve requirement from 40% of forecasted hourly solar generation to a fixed 400 MW, 8760 hours a year, the results are very different. Continuing our example, on a cloudy day solar might be forecast to produce only 100 MW. The 40% reserve requirement would require 40 MW of reserves. The conventional generation would supply 4900 MW of the 5000 MW load. It would hold 40 MW of the freed-up 100 MW in reserve. 4940 MW of conventional generation capacity would need to be available. A 400 MW reserve requirement

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[7] Response to South Carolina Conservation League and Southern Alliance for Clean Energy Third Data Request, 3-18.

[8] Why the use of "blended" results does not fix this problem is discussed in the next section of this report.

[9] Response to South Carolina Conservation League and Southern Alliance for Clean Energy Third Data Request, 3-18.

[10] For this simple example we can ignore the contingency and load following reserve requirements which are the same with and without solar.

would have a very different result. Solar would still supply 100 MW and conventional generation would still supply 4900 MW but the utility would now need to keep 400 MW of conventional generation in reserve. That creates a 5300 MW conventional generation capacity requirement. That is, 300 MW of additional conventional generation capacity that was not required in the non-solar case. This added 300 MW[11] of generation capacity performs no useful function, it is simply an uneconomic burden created to simplify the analysis and solve a problem created by SCE&G's own modeling choices.

The fact that utilities often have excess reserve capacity available at night, when solar output is zero, does not eliminate the concern. It only takes a few hours of increased capacity requirement over the multi-year study length to create significant increased costs. Further, the production cost optimization modeling will likely routinely incur higher costs as it recommits and redispatches generators to maintain the high reserve requirements.

Recommendation: The Commission should direct SCE&G to accurately model actual hourly reserve requirements using appropriate and capable modeling tools.

Blending of Production Cost Modeling Results is Not an Appropriate Solution

As indicated in the following description, Navigant recognized that imposing a fixed solar reserve requirement 8760 hours a year is not appropriate and they therefore developed a technique to try to correct this deficiency:

> "Because the solar forecast is not the same each day, Navigant then blended the results of the PROMOD® runs with the different levels of reserves to account for days in which less solar is forecasted than others. For example, the analysis calculated integration costs for Solar Case 2 using the following proportions of days in which these levels of reserves must be maintained:
>
> - Solar Case 2 level of reserves is needed 38% of the days
> - Solar Case 1 level of reserves is needed 51% of the days
> - Baseline level of reserves is needed 12% of the days"[12] (pages 18-19)
>
> "If the maximum operating reserve increases were assumed to be maintained every day, the estimate of integration costs would be too high. PROMOD® does not allow operating reserve levels to change day-to-day. Therefore, in order to incorporate the days with lower requirements, Navigant calculated the costs using varying levels of operating reserves and then blended those costs using weightings tied to the proportion of days with the appropriate level of solar uncertainty."[13] (page 20)

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[11] 360 MW, actually, since there is less than 1% chance that 60 MW of reserves will be needed.
[12] Direct Testimony of Matthew W. Tanner, Ph.D., Exhibit No. (MWT-2), *Cost of Variable Integration*, Navigant Consulting, February 2019.
[13] Direct Testimony of Matthew W. Tanner, Ph.D., Exhibit No. (MWT-2), *Cost of Variable Integration*, Navigant Consulting, February 2019.

Further, the *Cost of Variable Integration* report itself states:

> "An outcome of the solar uncertainty analysis, described in more detail in Section 3, is that the level of solar generation uncertainty depends on the level of solar generation. The amount of reserves that need to be held by SCE&G for variable integration depend on the level of forecasted solar generation. This dynamic is incorporated into the study analysis by blending the production costs of several cases operating the system with different levels of operating reserves to account for the day-to-day variability in the overall requirements." (pages 18-19)
>
> "To ensure that the analysis does not overestimate the costs to integrate the SC2 reserves, PROMOD was run with each of these levels of reserves and then the results were blended using the weighted average of costs tied to the number of days that each level of reserves was required." (page 27)

This approach of "blending" results from production cost modeling runs with different reserve requirements is completely inappropriate and does not fix the problem. If high costs result from modeling excessive reserve requirements in hours when solar generation is not producing, then those costs are not real, and it does little good to "blend" them based on the number of hours solar generation was producing. In the simplistic example given above it would not be appropriate to say that the 300 MW added conventional generation capacity requirement should be reduced to 150 MW because it was only calculated in one of the two cases. In that example, the higher cost was a complete artifact of the flawed modeling of the reserve requirement and it should be eliminated, not "blended."

Recommendation: The Commission should direct SCE&G to accurately model actual hourly reserve requirements. If the modeling tools or techniques are not adequate to represent actual conditions and requirements, SCE&G should fix or replace them.

Additional Existing Sources of Reserves

SCE&G has additional existing sources of reserves, currently available at little or no additional cost, that could be used to facilitate the integration of solar generation. As discussed above, off-line CC units should be able to supply reserves for 4-hour solar forecast errors. The Fairfield pumped storage plant pumping load is capable of providing solar forecast error reserves, as is the off-line generation capacity of Fairfield (if there is sufficient storage available). Additional interruptible load is also available for use as a solar forecast error reserve. SCE&G should not impose additional costs to add reserves that duplicate capacity that has already been paid for.

The reserve capabilities of the Fairfield pumped storage plant and interruptible load will be discussed further below. First it is important to note that the solar reserve shortfalls (and the actual need for additional reserves to be standing ready to respond) are relatively infrequent, averaging 16 event hours per year.[14] Actual reserve responses to solar generation declines will be even less frequent.

It would be imprudent for SCE&G to meet such an infrequent need for dependable capacity through expensive additional combustion turbine capacity if less expensive means such as interruptible load are available. The frequency of solar forecast reserve shortfalls is discussed below.

Appropriate Reserves for Infrequent Reserve Shortfalls

The *Cost of Variable Integration* report states that production cost modeling was used to model the SCE&G power system with only the 240 MW of reserves required by VACAR for contingencies and the 40 MW of reserves SCE&G requires with no solar generation:

> "PROMOD was used to simulate the system operation in each solar penetration scenario and the number of hours in the forecast period in which SCE&G was not holding sufficient reserves to account for solar uncertainty was calculated. In each of these scenarios, the hours with insufficient reserves occurred in all seasons across the year.
>
> - Baseline scenario – 74 hours
> - Solar Case 1 – 102 hours
> - Solar Case 2 – 201 hours" (Pages 24-25)

The response to South Carolina Conservation League and Southern Alliance for Clean Energy Third Data Request 3-22 states "Please note that on March 5, 2019, SCE&G filed a Corrected Exhibit No._(MWT-2) which changed "Solar Case 2 – 201 hours" to "Solar Case 2 – 196 hours". The Excel workbook Attachment to Response 3-22 SC2.xlsx, which was to list all hours of reserve shortfalls, however, contains only 193 hours of reserve shortfalls.

The 193 reserve shortfall hours do not represent times when the simulated power system would have less generation than load. Rather, they instead represent hours when reserves would be insufficient *if* solar generation happened to experience the maximum decline during that hour. Figure 1 shows the distribution of reserve shortfall events by year.

[14] As discussed further below, the *Cost of Variable Integration* report identifies 193 reserve shortfall events in 12 years of modeling. (Pages 24-25).

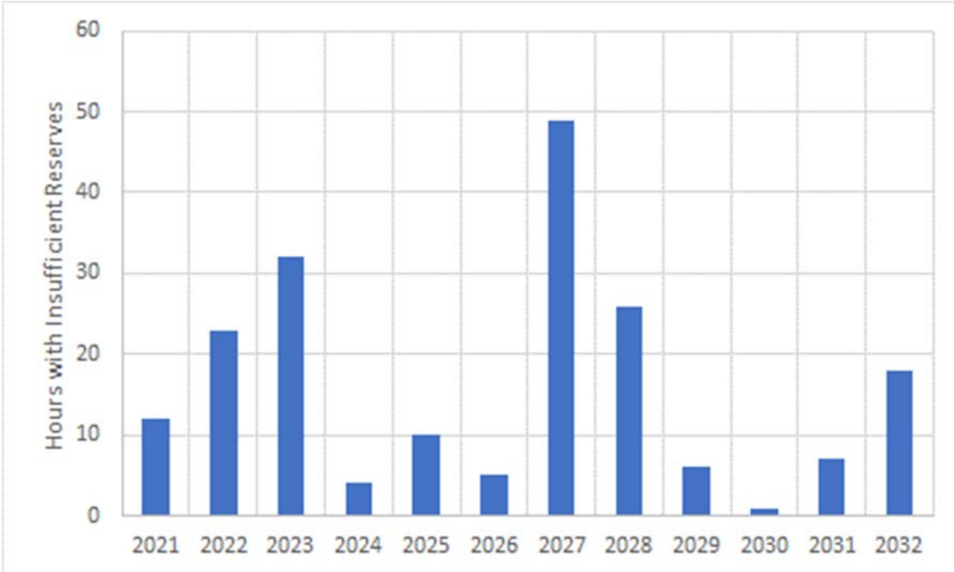

Figure 1 Potential reserve shortfall events by year for the 1050 MW SC2 solar case.

Figure 2 shows the size distribution of the potential reserve shortfalls.

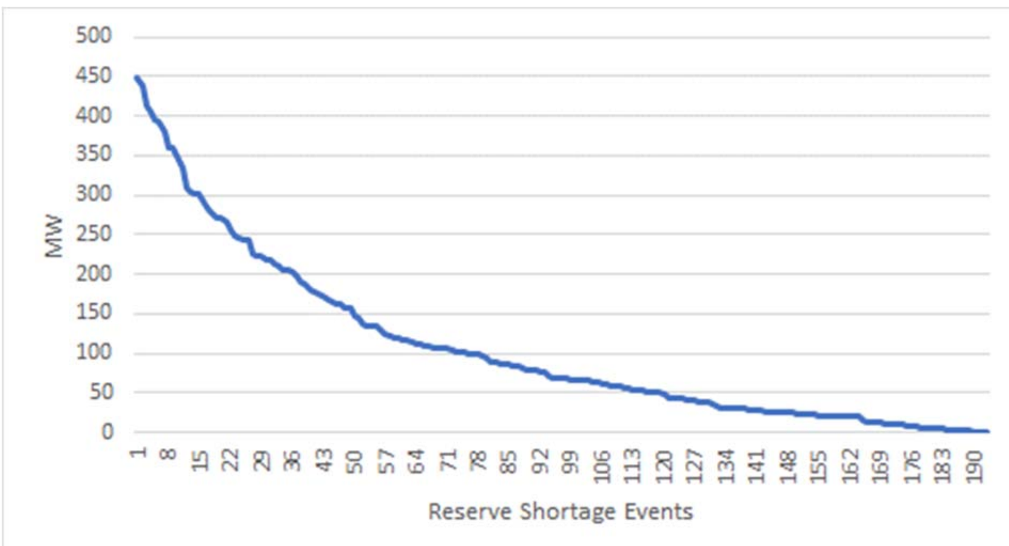

Figure 2 There are very few large reserve shortage events for the SC2 1050 MW solar case.

Reserve shortfall events occur during all days of the week and all months of the year except for January and December. Figure 3 shows that reserve shortfall events occur during all hours from 8am to 9pm.

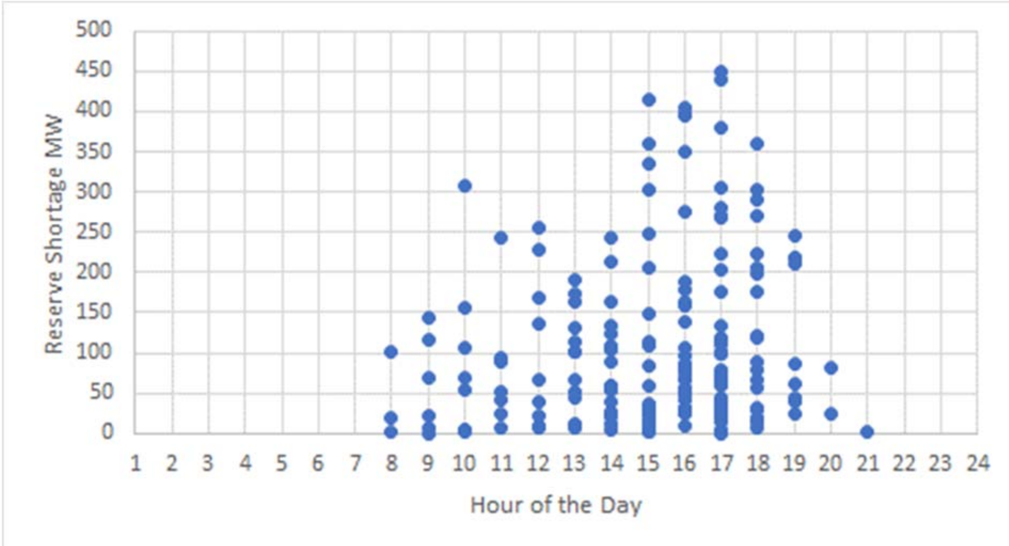

Figure 3 Reserve shortage events for the SC2 1050 MW solar case occur throughout the daylight hours.

The number of reserve shortage events and their size are important because they show that solar reserve shortage events are like mild conventional generator contingencies. They are "mild" because they do not require very fast spinning-reserve response, in fact they do not even require the 10-minute response of non-spinning contingency reserves. The very nature of cloud-driven solar declines results in ramping down over many minutes, not instantaneous tripping.

Fairfield Pumped Storage Plant

Based on the year of hourly PROMOD SC2 case results for 2030, the Fairfield Pumped Storage plant is only credited with supplying reserves when it is already on-line and generating. The reserve amount is then the difference between the 576 MW plant generating capacity and the current generation level (further limited by the current reservoir level). In the 2030 SC2 case, this was an impressive 308 MW reserve average for 1336 hours.

Fairfield has additional reserve capability that could be used for integrating solar generation. The Fairfield Pumped Storage plant can switch from pumping to generating in less than 15 minutes.[15] That is too slow to allow Fairfield to be counted as a non-spinning contingency reserve, but it is much faster than necessary for solar integration reserve.

The 2030 SC2 PROMOD case results show the Fairfield reservoir level above 576 MWH (1 hour of generation at full output) for 7736 hours. That would allow an additional 6199 hours per year of 576 MW reserve supply in addition to the 1336 hours that is already credited for on-line generation reserves.

[15] Response to South Carolina Conservation League and Southern Alliance for Clean Energy Third Data Request, 3-4.

Fairfield could supply additional reserves while pumping. As noted above, SCE&G states that Fairfield can switch from pumping to generating in less than 15 minutes. The pumping load should be available as a reserve, in addition to the 576 MW of generation capability. Fairfield is modeled as pumping during 2075 hours (24% of the time) in the 2030 SC2 PROMOD simulation, with an average 241 MW and maximum 664 MW pumping load. The 2075 hours are already included in the 7736 hours with adequate reservoir capacity but the 241 MW average, 664 MW maximum of reserves capacity is additional. Figure 4 shows that pumping is expected to occur throughout the day, not just at night. These added reserves can be very effective for solar integration.

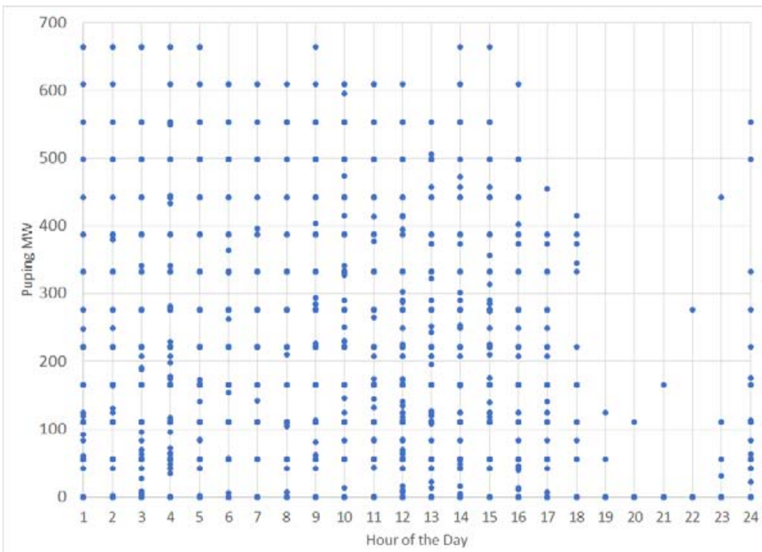

Figure 4 Fairfield was pumping for 2075 hours in 2030[16]

The hours of Fairfield pumping shown in figure 4 clearly overlap the hours of potential reserve shortfalls shown in Figure 3.

Recommendation: The Commission should direct SCE&G to count Fairfield generation as available reserve for integrating solar generation whenever Fairfield is off-line or pumping and there is sufficient storage available. In addition, the Fairfield pumping load should be counted as available reserves for integrating solar generation.

Additional Existing Demand Response

The 2030 SC2 PROMOD case results include 100 MW of Interruptible Load as available reserves in all hours. The *Cost of Variable Integration* report states that "SCE&G also has 100 MW of interruptible load that can be used to meet reserve requirements."[17] (page 9)

[16] Analysis of Response to South Carolina Conservation League and Southern Alliance for Clean Energy Third Data Request, 3-25, Attachment to Response 3-25.xlsx.

The 2018 Integrated Resource Plan states that "SCE&G has over 200 megawatts of interruptible customer load under contract. Participating industrial customers receive a discount on their demand charges for shedding load when SCE&G is short of capacity."[18] (page 16)

When asked why only 100 MW of interruptible load was included as available to meet solar forecast error reserve requirements SCE&G responded that VACAR requires SCE&G to maintain 200 MW of contingency reserves and that "[p]ursuant to VACAR requirements, up to one-half of this reserve generation capability, or approximately 100 MW, may be met by interruptible load" . . . "SCE&G does not believe it would be appropriate, prudent, or reasonable to rely upon interruptible load to meet its need for daily operating reserves used to follow load and smooth generation."[19]

Although the type of demand response SCE&G currently has is not appropriate for "daily operating reserves used to follow load and smooth generation," it is the type of reserves required to facilitate solar generation integration. As discussed above in the section titled "Appropriate Reserves for Infrequent Reserve Shortfalls," Navigant and SCE&G have identified a need for reserves to cover infrequent reserve shortfall events. Further, these are reserve shortfall events; additional reserves are needed to stand ready to respond. Actual response will be required much less frequently, making interruptible load an ideal provider of this type of reserve.

Recommendation: The Commission should direct SCE&G to count the additional 100 MW of interruptible load that VACAR does not permit SCE&G to count towards the contingency reserve obligation as being available to help integrate solar generation.

Capabilities of Current Solar Generators

When discussing options for dealing with solar impacts on the power system the *Cost of Variable Integration* report states:

> "Note that there are methods for solar units to provide flexibility and ramping to the system. Although this may be a feasible alternative in the future, this possibility has not been considered in this analysis because SCE&G cannot implement it unilaterally but only with technological changes by the solar facility owners." (page 28)

All new solar plants greater than ~1 MW could easily be placed on automatic generation control.[20] This is not a technology or implementation cost issue. SCE&G is in control of the

[17] Direct Testimony of Matthew W. Tanner, Ph.D., Exhibit No. (MWT-2), *Cost of Variable Integration*, Navigant Consulting, February 2019.
[18] 2018 Integrated Resource Plan, SCE&G, 2/28/2018.
[19] Response to South Carolina Conservation League and Southern Alliance for Clean Energy Third Data Request, 3-21.
[20] *Investigating the Economic Value of Flexible Solar Power Plant Operation*, Energy and Environmental Economics Inc., October 2018.

interconnection process and simply has to develop technically justified requirements with fair compensation. All parties should benefit when the power system is economically optimized and reliably operated.

Requirements of Solar Generators vs. Limitations of Conventional Generators

Solar and wind generators are valued because of their zero-marginal-cost (and zero emissions) energy. With zero marginal cost any economically optimized power system will naturally utilize as much solar and wind energy as is currently available and that can be reliably integrated into the power system.

No generation resource is perfect. For example, nuclear generators are attractive because of their low marginal energy cost, but they are inflexible, do not follow load well, and can't provide contingency reserves. A power system with only nuclear units would be inoperable. Many conventional thermal generators are more flexible than nuclear units but have high minimum loads and long startup and shutdown times. However, conventional generators are not typically assessed integration charges despite their high minimum loads, long startup times, or inflexibility.

When assessing the impact of solar generators on power system operations, the Company and Commission should take a similar approach as they do to conventional generation: integration charges may not be appropriate unless they are assessed on all technologies. Are integration charges being considered for solar generators only because they are the latest addition to the generation fleet? Would a new thermal generator, even a new combined cycle generator, be assessed an integration charge for its high minimum load or its long startup time? SCE&G's proposal to assess a variability integration charge on solar generators is especially discriminatory because it is largely based on an excessive and technically-incorrect four-hour forecast error, which the Company claims is required even though the Company states that most combined cycle plants only require two hours to start.

It may be more appropriate simply to recognize that each generation technology has limitations and to then optimize the power system around those limitations. Alternatively, maybe all generation technologies should be assessed charges to the extent that they fall short of perfection.

Next Steps – What Should Be Done?

The analysis methodology should be modified, and the modeling tools upgraded. The Commission should direct SCE&G to take the following steps:

- Model production costs in a manner that accurately reflects the aggregation benefits that naturally reduce forecasting errors as the solar generation fleet grows. Solar output and forecast data should be analyzed from a realistic representation of geographically diverse and realistically sized solar plants for the high penetration solar cases.

- Re-do the solar forecast error analysis that determined the MW reserve requirements, and use a 2-hour ahead or 1-hour ahead solar forecast. Alternatively, if the 4-hour ahead solar forecast is kept, then off-line combined cycle (CC) units should be counted as available reserves.
- Model production costs with reserve requirements adjusted hourly to reflect the actual solar conditions. The analysis method of "blending" results from multiple production cost modeling runs, each with fixed reserves imposed 8760 hours a year, should be discarded. If the modeling tools or techniques are not adequate to represent actual conditions and requirements, SCE&G should fix or replace them.
- Select reserve technologies and mitigation strategies that take advantage of the infrequent times of high additional solar forecast error reserves, and the even more infrequent times of required reserve response.
- Model production costs to include the Fairfield pumped storage plant pumping load and off-line generation as available reserves for solar integration, subject only to the constraint of available storage capacity.
- Model production costs to count the additional 100 MW of interruptible load that VACAR does not permit SCE&G to count towards the contingency reserve obligation as available reserves for solar integration.

Once these steps are taken, it will be possible to begin to determine if any solar integration charge is warranted. SCE&G should file this updated analysis as an improved starting point for beginning to evaluate the interrelated issues of variable integration costs, the value of solar plus batteries, and curtailment.

SCE&G should also consider utilizing a Technical Review Committee (TRC), composed of outside experts on variable renewables integration. TRCs have been successfully used by many utilities to help guide their integration studies and to utilize the latest and best integration study practices.[21] The Energy Systems Integration Group has published guidelines for TRC involvement in renewables integration studies.[22]

Conclusions: The *Variable Integration Charge* Study is Fundamentally Flawed, and the Resulting Variable Integration Charge is Unsubstantiated and Indicates that SCE&G May Integrate Renewables in a Manner that Creates Ongoing, Excessive Fuel and Reserve Capacity Costs

The analysis methodology presented in the February 2019 SCE&G *Variable Integration Charge* report is deeply flawed, and the resulting solar integration charge is unjustified. Of even greater

[21] For example: Idaho Power, Portland General Electric, Arizona Public Service, BC Hydro, Public Service Colorado, Pan Canadian Wind Integration Study, ISO-New England, Pacificorp, Public Service of New Mexico, SMUD, the Western Wind and Solar Integration Study, Eastern Wind Integration and Transmission Study.
[22] https://www.esig.energy/resources/principles-trc-involvement-wind-integration-studies/.

concern, it raises the possibility that SCE&G will not follow best practices in forecasting and operating its fleet to integrate low-cost renewable energy. The proposed methodology is not based on a realistic estimation of actual and appropriate solar forecasting errors because solar aggregation was not properly included and the 4-hour ahead forecast is two to three times longer than will be required with SCE&G's mix of conventional generators. Alternatively, off-line CC units should be included as available reserves.

The analysis used an unrealistic and inappropriate fixed solar reserve requirement, imposed 8760 hours per year. The analysis method of "blending" results from production cost modeling runs with different reserve requirements does not fix the problem. Additional reserves currently available from the Fairfield pumped storage plant and from interruptible load are appropriate for the solar reserve response time requirement and match the response frequency requirements. These reserves should be included in the production cost modeling.

Appendix A

Qualifications of Brendan Kirby, P.E.

Brendan Kirby is a private consultant with numerous clients including the Hawaii Public Utilities Commission, National Renewable Energy Laboratory (NREL), the Utility Variable-Generation Integration Group (UVIG), Electric Power Research Institute (EPRI), the American Wind Energy Association (AWEA), Oak Ridge National Laboratory, and others. He retired from the Oak Ridge National Laboratory's Power Systems Research Program. He has 44 years of electric utility experience, and he has been working on restructuring and ancillary services since 1994 and spot retail power markets since 1985.

Mr. Kirby's interests include electric industry restructuring, bulk system reliability, energy storage, wind and solar power integration, ancillary services, demand side response, renewable resources, distributed resources, and advanced analysis techniques. He has published over 180 papers, articles, and reports. He coauthored a pro bono amicus brief cited by the Supreme Court in their January 2016 ruling confirming FERC demand response authority. He has a patent for responsive loads providing real-power regulation and is the author of a NERC certified course on Introduction to Bulk Power Systems: Physics / Economics / Regulatory Policy. He served on the NERC Standards Committee and the Integration of Variable Generation Task Force. He has participated in the NERC/FERC reliability readiness reviews of balancing authorities and reliability coordinators, performed field investigations for the US/Canada Investigation Team for the 2003 Blackout, and has appeared as an expert witness in FERC and state litigation. He has conducted research projects concerning restructuring for the NRC, DOE, NREL, EEI, AWEA, UWIG, numerous utilities, state regulators, and EPRI.

Mr. Kirby is a licensed Professional Engineer with a M.S degree in Electrical Engineering (Power Option) from Carnegie-Mellon University and a B.S. in Electrical Engineering from Lehigh University.